Petroleum and Coal

Article **Open Access**

Using Dual Fracturing Technique to Control Hydraulic Fracturing Propagation

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Received December 14, 2019; Accepted February 4, 2020

Abstract

Hydraulic fracturing, being one of the most widely used production technologies used by many operators, can lead to a severe increase in water production when there is low stress contrast between the water bearing formation and the net pay. In the case of near oil water contact, that can cause an increase in water production when the fracture geometry grows vertically below that water level. Dual fracturing techniques can be a permanent solution for hydraulic fracturing these reservoirs. This technique depends on creating an artificial barrier that may hinder the growth of the water bearing zones and keep the fracture growth in the pay zone. This technique showed a high success rate in the western desert, Egypt, in several oil & gas wells with different distances between the bottom of perforation and hydrocarbon-water contact. After optimizing eleven case studies from different fields, conclusions were about the effective factors for the success of the dual fracturing technique. This paper provides a complete workflow to select the proper candidate for this technique. It also explains with practical cases from western desert Egypt how to conduct this technique successfully from design to execution and evaluation.

Keywords: *Artificial barrier; Candidate selection; Dual fracturing; Hydraulic fracturing; Stimulation; Water management.*

1. Introduction

The present worldwide daily water production from oil wells averages roughly 3 BWPD for every barrel of oil. Water production costs money to lift water and then dispose of it. In a well producing oil with 80% water cut, the cost of handling water can increase the lifting cost more than two of the normal lifting costs. The water control technology is intended to reduce the costs of producing water as this co-production of water can cause corrosion and scales in surface facilities and down-hole equipment.

When the hydraulic fracture job is needed in a well due to reservoir tightness or formation damage, and there is a nearby water zone, the need to control the hydraulic fracture propagation not to hit water zone as once that happened the well will be lost due to water coning as the water mobility will be higher than hydrocarbon mobility. The oil industry has practical two solutions for water production problems associated with hydraulic fracturing; the first solution is to pump the relative permeability modifier with the fracture fluid [1].That is to reduce of the relative permeability to water, so it causes reduction of the mobility of water relative to oil and gas but that has some disadvantages which are that method needs special core analysis (SCAL), and that method is not a permanent solution, so it doesn't fit with strong reservoirs.

The second method for preventing water production from nearby zone after hydraulic fracturing is to control the fracture propagation not to hit that critical zone. This technique places an artificial proppant barrier below the pay zone, close to the water-oil contact, creating high resistance to the fluid movement and restricting pressure transmission, thus arresting uncontrolled vertical height growth of fractures.

These barriers are created before the actual main fracture treatment by pumping heavy proppant slurry at fracturing rates carried in a fracturing fluid loaded with high breaker dosage concentration. Artificial barrier placement was patented by Prater [2] was applied by Nguyen *et al.* [3] and Arp *et al.* [4] and was introduced to be tried in the western desert by Salah *et al.* [5] and showed high success rate.

The high breaker dosage concentration breaks the fracturing fluid fast, thus allowing the quick proppant settling to the bottom of the created fracture as like what Nitters *et al.* proved [6]. That method is not temporary solution, and it doesn't need special core analysis and showed success rate, but there is no one studied its control points and the feasibility of that method so this paper study that success cases deeply to try to set some control points that help decision makers to select the proper method for the preventing nearby water production after hydraulic fracturing.

2. Dual fracturing technique

In some fracturing jobs, a radial fracture growth pattern happens when the net fracturing pressure during the job increases more than the stress contrast between formations. As the created fracture geometry is constant, the greater this vertical fracture growth, the lesser the lateral fracture growth, which often reduces the production improvement factor, especially in low permeability reservoirs where the fracture half-length is required.

Moreover, the condition of uncontrolled height growth may also result in unwanted downward fracture growth out of the zone of interest, which can often increase the risk of water influx. In addition, the combination of a radial growth pattern and density contrasts in treatment fluid may cause proppant convection to the bottom of the fracture, which could reduce production results than the estimated one.

Dual fracturing technique is a method of placement for an artificial barrier below the hydraulic fracture to prevent its growth to the undesired zone. Dual fracturing consists of an initial fracturing treatment followed by the main treatment. The settle frac treatment featured a low-viscosity fluid with higher breaker dosage concentration and a proppant to create enough length and settled height. During the settle slurry stages, the proppant concentration is scheduled up to 2 ppg, and then the created fracture is allowed to close and give an opportunity for the proppant to settle in the lower part of that fracture. This treatment creates an artificial barrier that limits downward fracture growth to the undesired water zone.

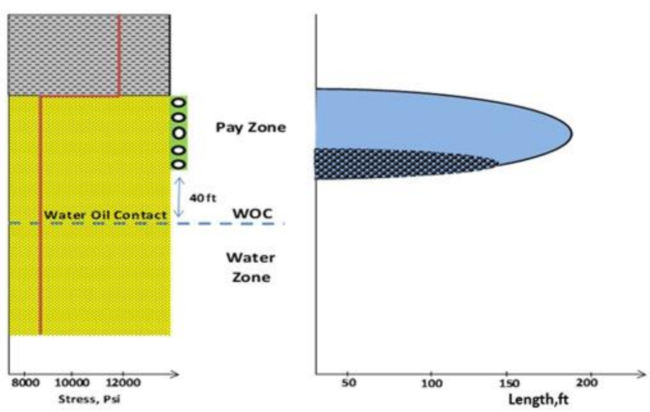

Figure 1. Artificial barrier placement schematic [5]

The main fracturing treatment can then be simulated by increasing the stress values below the pay zone. This model allows adequate propped fracture length in the pay zone and a good conductivity contrast. This settle stage is followed by the injection of high density proppant carried in a low viscosity fluid system.

The dual technique involves pumping a small fracture treatment ahead of the main fracture treatment. Initially, a small viscous pad volume is pumped ahead of the proppant slurry to open the fracture in the pay zone, creating a fracture channel, Figure 1.

3. Application of dual fracturing technique

This technique was widely applied to more than 11 well from different fields with different properties. The following is the example of one of those cases:

The wells P1 was drilled in targeting (S) sandstone reservoir at a depth of +/- 12,230 ft, which is overlain on the shale barrier. Below the shale barrier, there is a sandstone formation, which is a strong aquifer, as shown in Figure 2. (S) formation is high permeability formations, so it doesn't need hydraulic fracturing to produce, but after two years of production from several wells the reservoir pressure dropped below the bubble point pressure, so the well suffered from multiphase flow damage as the reservoir pressure is slightly higher than bubble point pressure so liberation of gas in near wellbore area cause additional skin. The Multiphase flow lessens the effective permeability of oil, so the best solution for that problem to increase the area of the surface area of the reservoir around the wellbore to reduce that multiphase flow effect using a hydraulic fracture job. The summary of well data is tabulated in Table 1.

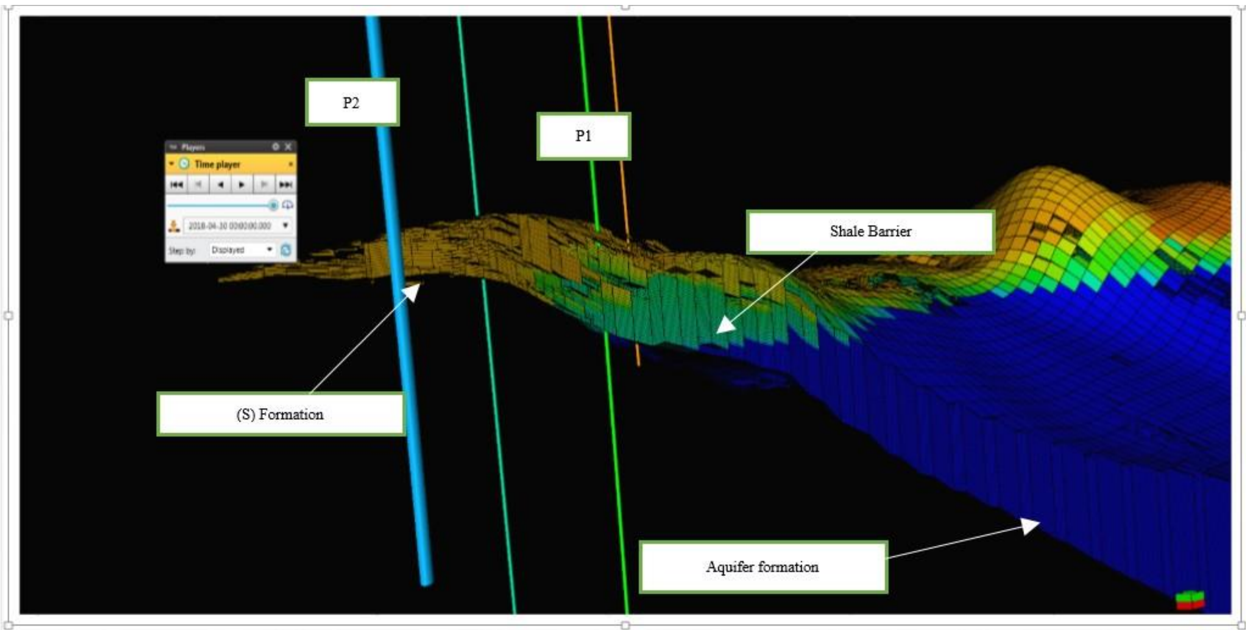

Figure 2. Generalized lithology succession of (S) Formation

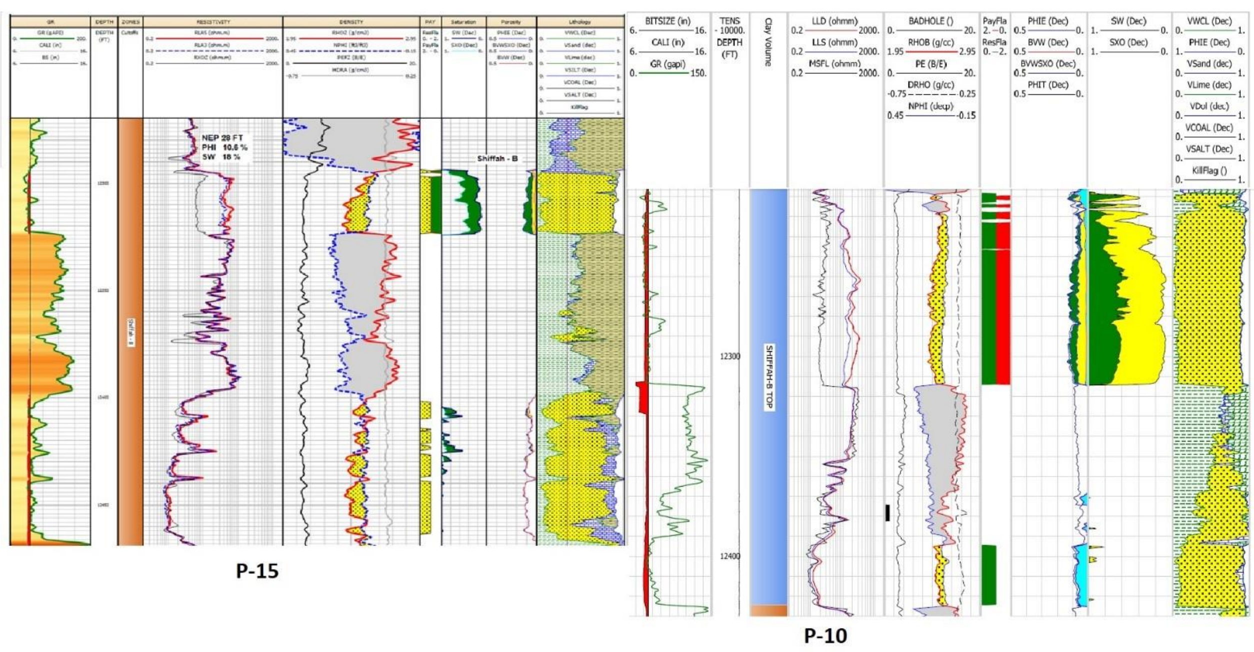

Figure 3. Lithology interpretations for the well P1

Table 1. (S) Formation properties, P concession

Reservoir parameter	Value	Reservoir parameter	Value
Reservoir pressure, Psi	3300	Total vertical depth, ft.	12230
Reservoir temperature, F	280	Porosity, %	9.4
Permeability, md	70	Water saturation, %	20
Net Pay thickness, ft.	95		

The geomechanical model was constructed using the well logs (that is show in Figure 3) to estimate the rock mechanical properties and model the stress profile using a dipole sonic log in an offset well P-05. In-situ stress contrasts between the pay zone and the adjacent layer for this 'base case' were 1700 psi for the overlying layer (as shown in Figure 4), but the stress difference between the zone and is lower than the expected net pressure during the job.

Due to the high permeability of formation which cause high leak off during job pumping and cause proppant bridging and more net pressure increase which cause height growth toward the zone (Expected net fracturing pressure during the job because of proppant bridging is 3,600 psi as per Figure 5) so the shale barrier below the pay zone is not effective barrier as the ratio of net pressure to stress difference is two and the ratio between pay zone to barrier is greater than one, so the hydraulic fracture is expected to propagate through the barrier to the aquifer which shown on Figure-3 & Figure-4 at depth 12,396 ft-MD.

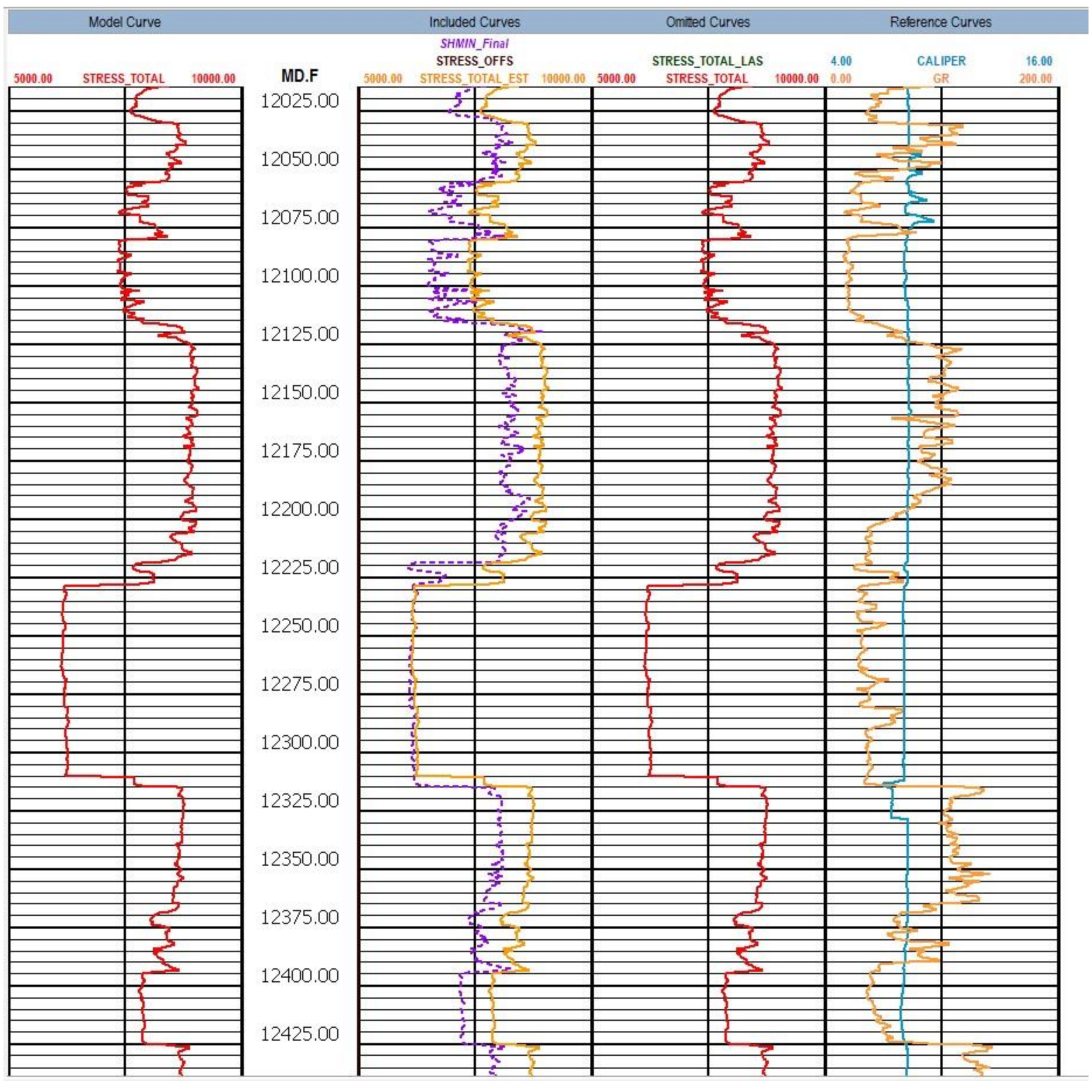

Figure 4. Stress profile for stimulation design which is created by dipole sonic log processing of offset Well P-05

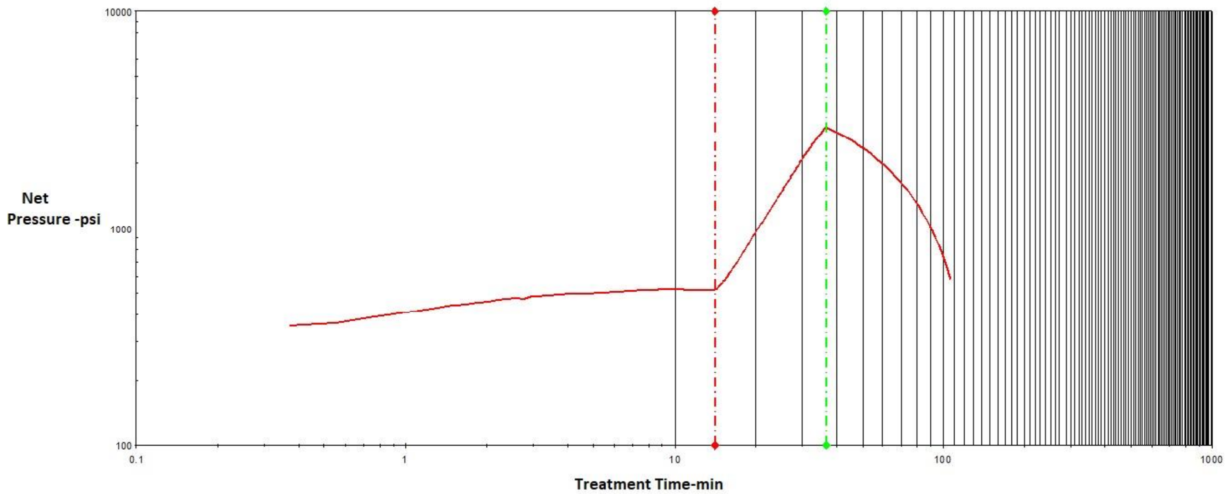

Figure 5. Expected Net pressure curve vs. treatment time in the well P1

So, the dual fracturing technique was decided in that well to be conducted, as shown in Table 2.

Table 2. Dual fracturing technique pumping Schedule for P1

Stage	Slurry volume BBL	Slurry Rate BPM	Pump Time Min.	Fluid Name	Fluid Volume gal	Proppant Name	Prop conc. PPA	Prop. mass Lb
PAD	155.4	30	10	Cross-Linked gel # 45	6527		0	0
0.5 PPA	66	30	2.2		2632	HSP 20/40	0.5	1100
1 PPA	95.4	30	3.7		3351		1	3526
2 PPA	173.1	30	6.1		6886		2	10374
flush	176.1	30	5.9	Linear gel #45	7392		0	0
Shut in for 5 hrs (For Fracture Closure)								
Stage	Slurry volume BBL	Slurry Rate BPM	Pump Time Min.	Fluid Name	Fluid Volume gal	Proppant Name	Prop conc. PPA	Prop. mass Lb
PAD	231.7	30	8	Cross-Linked gel (gel loading 45 Lb/1000 gal)	9700	HSP 20/40	0	0
One	45	30	1.5		1754		1	893
Two	71.6	30	2.4		2351		2	2834
Three	72	30	2.4		2629		3	4120
Four	107	30	3.6		4457		7	8000
Five	153	30	5.1		2458		5	13845
Six	44.5	30	1.8		1930		6	3381
Seven	39	30	1.3		1577		6	6519
flush	168.1	30	5.6	Linear gel (gel loading 45 Lb/1000 gal)	14018		0	0

The prejob minifrac was pumped and showed the following results shown in Figure 6 and Table 3.

Table 3. Summary of G-function analysis for minifrac on P1

Parameters	Value
Instantaneous shut in pressure	8350 psi
Instantaneous shut in pressure gradient	0.68 psi/ft
Closure pressure	6957 psi
Closure pressure gradient	0.57 psi/ft
Fluid efficiency	37 %
Net pressure	1393 psi

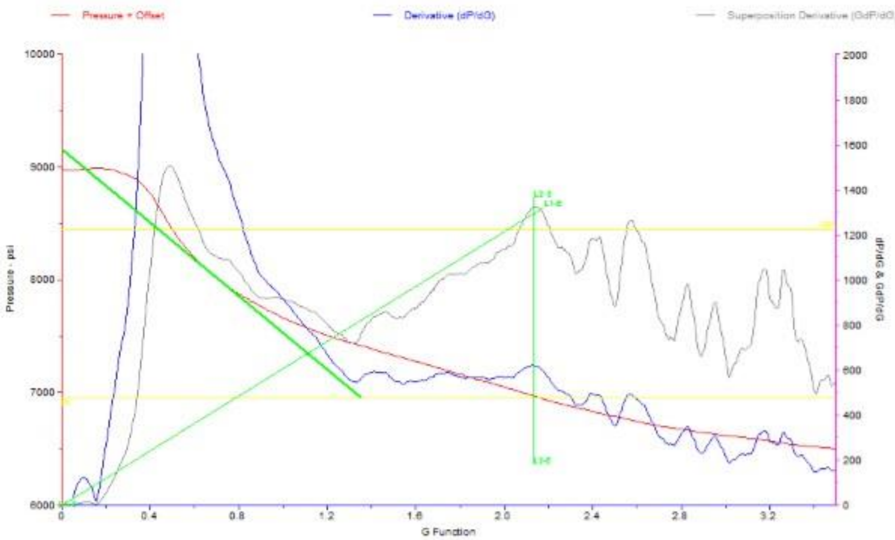

Figure 6. G-Function analysis of minifrac P1

An artificial barrier was placed ahead of the main fracture treatment by pumping 15,000 lbs of 20/40 mesh proppant at 2 lb/gal using 19,000 gals of a 45 lb/Mgals borate cross-linked gel; the same fluid system as the main frac. The 19,000 gals of gelled fluid included a 6,500 gal pad stage followed by 12,500 gals of proppant-laden fluid. A higher breaker concentration was used to ensure rapid degradation of the gel viscosity and proppant settling to the bottom of the fracture, thus creating the artificial barrier. Three types of breakers used during the placement of the artificial barrier with maximum dosage. The pressure response of the formation is shown in Figure 7.

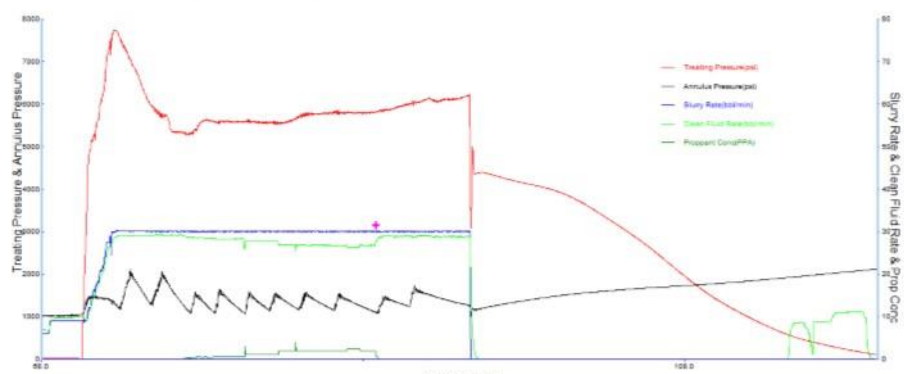

Figure 7. Pressure response of the first step of dual fracturing on P1

Then the leak off of fracture fluid after the first step was analyzed using the G-function and showed the G-fuction curve in Figure-8 and summary of results as per table-4.

Table 4. Summary of G-fuction analysis results of the First step of dual fracturing on P1

Parameters	Value
Instantaneous shut in pressure	9517 psi
Instantaneous shut in pressure gradient	0.78 psi/ft
Closure pressure	7230 psi
Closure pressure gradient	0.59 psi/ft
Fluid efficiency	11 %
Net pressure	2287 psi

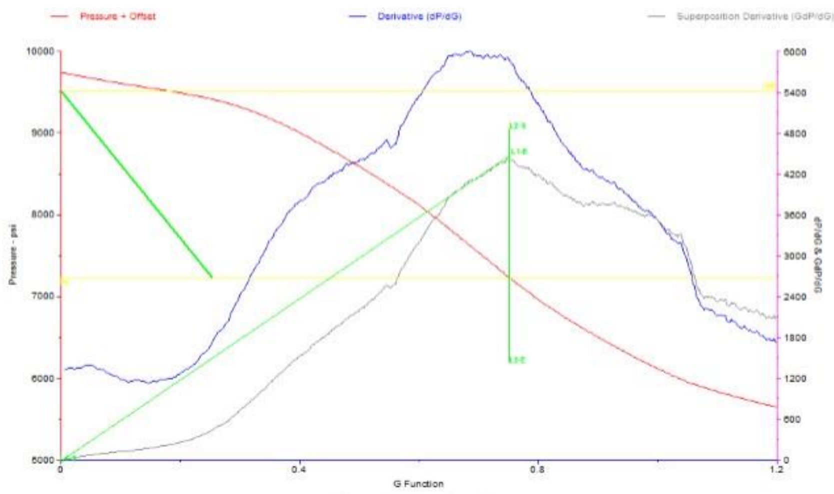

Figure 8. G-Function analysis of the first step of dual fracturing on P1

After pumping the stress barrier, the main fracture treatment was pumped. First, the pad stage was pumped with 45 lb/Mgals borate cross-linked gel at pumping rate of 30 bbl/min but as expected the net pressure started to increase due to the fast leak off of fracturing fluid in formations, but it didn’t drop during the treatment (confined fracture height growth indication) like shown in Figure-9.

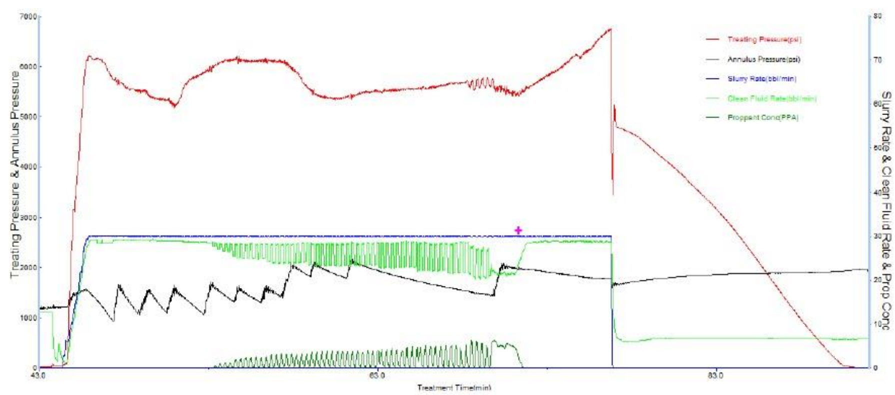

Figure 9. Pressure response of the first step of dual fracturing on P1

A total of 96,000 lb of 20/40 proppant was placed into the formation with 58,500 gal of borate- cross-linked gel.

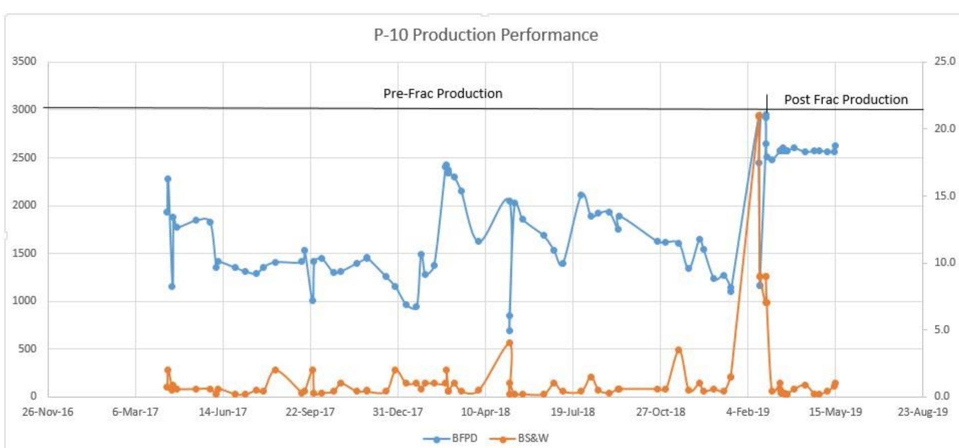

Figure 10. Production Performance for the well P1

The Well Performance after hydraulic Fracture job for P1 showed outstanding performance with low water cut, which confirms that the hydraulic fracture geometry was controlled successfully and prevented from hitting the water zone, as shown in Figure-10.

With the same workflow of previous well,dual fracturing was applied, and the summary of the operations was showed in table 5

Table 5. Summary of the wells subjected to dual fracturing

Well	Reservoir interval	Distance from BTM of perforation and water zone	ISIP gradient	Closure Stress Gradient	Settle Stage proppant (Lb)	PAD volume in First step of dual fracturing (gallons)	Proppant pumped in main Fracture Stage (Lb)	PAD volume in main Fracture Stage (gallons)
P1	(12,230-12,276) 46 ft (12,290-12,310) 20 ft	60	0.68	0.57	15000	6500	39600	9731
P2	(12294-12322) 28 ft	80	0.75	0.47	16500	7415	39600	6510
S1	(14512-14540) 28 ft	96	0.944	0.736	14000	6000	88000	15000
S4	(14536-14562) 26 ft	40	0.96	0.76	12800	6000	86400	16500
W5	(14900-14912) 12 ft (14929-14943) 14 ft	15	0.89	0.67	16000	6000	86400	11500
A1	(10676-10710) 34 ft	50	0.59	0.5	13200	5050	99277	13300
A2	(10,656’-10,671’) 15 ft	8	0.83	0.613	14000	6000	30000	13000
T1	(8918'-8930') 12 ft (8956'-8962') 6 ft	20	0.85	0.64	13200	6118	99200	16000
T2	(8,962 - 8,978) 16 ft.	52	0.88	0.65	13200	6700	99200	18000
SF1	(8,614-8,630) 16 ft	40	1.01	0.89	6633	5000	56000	15500

Table 6. Summary of observation for dual fracturing

Well	Production Performance after dual fracturing	Proppant Placement Success	Distance to nearby fault	Sand Quality	Permeability (md)	Target of Hydraulic fracture	Success to reach target
P1	Succeeded	Succeeded	No Nearby fault	Good	70	Bypass Near wellbore damage	Succeeded
P2	Succeeded	Succeeded	No Nearby fault	Good	50	Bypass Near wellbore damage	Succeeded
S1	Succeeded	Succeeded	No Nearby fault	Good	5	Bypass Near wellbore damage	Succeeded
S4	Succeeded	Not Successful placement	No Nearby fault	Good	3	Bypass Near wellbore damage	Succeeded
W5	Succeeded	Not Successful placement	520 m	Bad	30	Bypass Near wellbore damage	Succeeded
A1	Succeeded	Succeeded	1000 km	Good	2.3	Bypass Near wellbore damage	Succeeded
A2	Low rate, Hard to prove the success	Not Successful placement	200 m	Bad	0.5	Get large fracture half length	Failed
T1	Succeeded	Succeeded	No Nearby fault	Good	2.23	Bypass Near wellbore damage	Succeeded
T2	Succeeded	Succeeded	No Nearby fault	Good	3.7	Bypass Near wellbore damage	Succeeded
SF1	Low rate, Hard to prove the success	Succeeded	No Nearby fault	Bad	0.2	Get large fracture half length	Failed

From the previous observations for the success stories in dual fracturing techniques in sample wells we can conclude the factors that control the success of dual fracturing techniques.

The main philosophy of the dual fracturing technique is to conduct two fracture jobs in the same directions, so the stress state should be capable of keeping the fracture propagation in same directions so the difference between the minimum horizontal stress and maximum horizontal stress should be high enough to prevent hydraulic fracture re-orientation.

All formations that were conducted to dual fracturing technique are hard formations with young's modulus above 2,000,000 psi as the soft formations are not recommended due its geo-mechanical properties as the difference between the minimum and maximum horizontal stresses is not large enough to make the two steps of dual fracturing technique in the same direction as the added stress of proppant may divert the main fracture treatment to be in different direction.

Isotropic stress state is preferred for successful dual fracturing techniques. If the far-field stresses are in a significantly different direction from the orientation of the initial fracture propagation, the fracture will have to make a radical change in direction at some point. When the horizontal stresses are very similar, this will be a gradual change in direction, accompanied by plenty of fracture width. However, when there is a large contrast between these stresses, the change in direction will be a lot more abrupt and will introduce a dramatic reduction in width, leading to restricted flow. Large contrasts in horizontal stresses are typically found in formations that have experienced significant tectonic and other geological activity. Therefore, it is reasonable to assume that formations in geologically active areas, or with a significant history of faulting, will have an increased tendency towards tortuosity.

Dual Fracturing technique showed success in wells with low complexity and low far field tortusity, so detecting Complexity using Diagnostic fracture injection test and minifrac is essential to confirm the stress regime and calibrate the expected net pressure during the job.

The Nolte-Smith net Pressure curve with time should be observed during the two steps of dual fracturing to observe the net pressure values and slopes during the first step and expect the net pressure during main fracture treatment.

The Proppant Packing during the main fracture treatment (can be detected by positive Slope in nolte-smith net pressure curve, but not greater than 1) is a good sign for successful dual fracturing.

The Amount of stress added to the lower stress barrier can be easily calculated by applying the minifrac analysis workflow on the first step leak off period due to the low proppant concentrations of the first step and getting the value of added stress due to proppant in the first step.

The minimum horizontal Stress of the payzone should be within a reasonable value. It is recommended to conduct a dual fracturing technique when the minimum horizontal stress gradient is less than the vertical stress gradient by 0.2 psi/ft at least to prevent T-Shaped fracture geometry during the main fracture treatment. That was supported by field results.

Dual Fracturing technique showed higher conductivity of hydraulic fracturing with lower proppant volume. That, due to that, the proppant in the settle fracturing step resists the proppant transport away from the wellbore. That is the same results obtained by Barree *et al.* [7].

4. Conclusion

Dual fracturing techniques can be a good practical, effective method to prevent hydraulic fracturing propagation from hitting the undesired water zone below the pay zone. The technique includes pumping a small hydraulic fracture job and pumps a small amount of proppant with a high breaker dosage to settle below the pay zone and strengthen the stress barrier below the pay zone. Production data for the eleven wells confirmed the effectiveness of that permanent technique.

Diagnostic pumping before the job is needed to calibrate the calculated stress profile and identify the type of leak off to confirm the need for dual fracturing technique. This technique can be less effective in the wells near faults or in the reservoir containing natural fractures and fissures or with high far-field tortuosity wells. Also, it's recommended to be used when there is no barrier below the pay zone. This technique strengthens the already existing week stress barrier below the pay zone.

The dual fracturing technique adds some complexity to the main fracture, which may limit the placement of the planned amount of proppant to enhance well productivity to the target values. Dual Fracturing succeeded in increasing the conductivity of hydraulic fracturing but fails to introduce large half-length as the first step proppant resist the proppant transport in the main fracture stage.

Acknowledgements

The authors thank Khalda Petroleum Company management & Suez University for permission to present this paper in addition to all who contributed to the success of this project.

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